COMMONWEALTH OF VIRGINIA, ex rel.

STATE CORPORATION COMMISSION

CASE NO. PUE-2004-00068

Ex Parte: In the matter of establishing rules and regulations pursuant to the Virginia Electric Utility Restructuring Act for exemptions to minimum stay requirements and wires charges

By its *Order Establishing Proceeding* dated June 16, 2004, the Virginia State Corporation Commission ("Commission") established Case No. PUE-2004-00068 to promulgate rules and regulations and adopt a methodology for determining "market-based costs." This proceeding was established in order to implement amendments to two provisions of the Virginia Electric Utility Restructuring Act, Chapter 23 (§§ 56-576 *et seq.* of the Code of Virginia) ("Restructuring Act" or "Act"), as called for by Chapter 827 of the 2004 Acts of Assembly (Senate Bill 651). The amendments create new statutory provisions relating to the minimum stay requirements developed pursuant to § 56-577 E of the Restructuring Act and wires charges imposed pursuant to § 56-583 of the Act.

To focus interested parties' attention on the issues raised by the new statutory exemptions created by Senate Bill 651, the Commission requests that prospective representatives and other interested persons respond to any or all of a series of eleven questions. Responses to selected questions, prepared by counsel on behalf of A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative and Southside Electric Cooperative (the "Virginia Distribution Cooperatives"), Old Dominion Electric

Cooperative ("Old Dominion") and the Virginia, Maryland & Delaware Association of Electric Cooperatives ("VMD Association") (collectively, the "Cooperatives") are provided below.

Before proceeding with the questions and responses, the Cooperatives would like to offer some general comments on the new exemptions added to the Restructuring Act under Senate Bill 651. As will be seen in their responses to the Commission's questions, the Cooperatives maintain that it was neither planned nor intended that they be required to apply the added exemptions to their customers. To the Cooperatives, however, the heart of the matter lies in the question of what actual benefits can electricity consumers in Virginia expect to garner from application of these exemptions.

To the extent it could be established that some real, tangible benefits to the Cooperatives' members can be expected from the investment of time and money necessary to make the adjustments needed to implement these exemption programs (*e.g.*, participating in the development of new regulations, amending current terms and conditions of service, changing existing tariffs and developing new "market-based costs" tariffs), the Cooperatives likely would willingly embrace them. The Cooperatives' customers are not second-class citizens, and the Cooperatives would hope that they could make any program, rule or exemption that is shown to benefit electricity consumers in Virginia equally available to their customers. Still, at this time, the Cooperatives do not believe that expected benefits from the exemption programs have been shown. Neither do the Cooperatives believe it was intended, nor that it should be required, that they *must* make the subject exemptions available to their members. However, certain of the Cooperatives may want the flexibility to elect, at the discretion of the Cooperative's Board of Directors, to offer their customers the option of participating in the exemption programs once satisfied that the exemptions will produce some tangible benefits for the Cooperative and its members.

The Cooperatives appreciate the opportunity to provide these responses and to join with Commission Staff and other interested parties in the work group to provide input and otherwise participate in the development of rules applicable to the minimum stay and wires charge exemptions. The following are the Commission's questions and the Cooperatives' replies:

1. What new retail access rules and modifications to existing retail access rules are needed to implement the Minimum Stay and Wires Charge exemption programs?

The *Rules Governing Retail Access to Competitive Energy Services*, 20 VAC 5-312-10 *et seq.* ("Retail Access Rules") will have to be reviewed in detail to determine what new rules will be needed and what revisions must be made. Several provisions of 20 VAC 5-312-80. *Enrollment and switching* will need to be reconsidered, and additional subsections addressing the new exemptions would be appropriate in this section of the Retail Access Rules.

2. What verifiable milestone event(s) constitutes "the transfer of the management and control of an incumbent electric utility's transmission assets to a regional transmission entity?"

The requirement of a verifiable milestone event marking the transfer of an incumbent electric utility's transmission assets to an RTO/E is part of the basis for the Cooperatives' argument that the new exemptions were not designed or intended to be applied to the Cooperatives. None of the Virginia Distribution Cooperatives will be transferring either management or control of transmission assets to an RTO/E.

3. Do the legislated Minimum Stay and Wires Charge exemption programs apply to retail electric cooperatives? Explain why or why not?

Senate Bill 651 generated a notable measure of disagreement and debate as it wended its way through the legislative process. Along the way alliances were formed, competing legislation was proposed, alliances were broken and compromises were struck. At one point a proposal was made and language developed to permit the Cooperatives to opt-out, *en masse,* from the restructured, competitive market, which proposal the Cooperatives rejected. It was in the course of this process, prior to rejection of the opt-out proposal, that the notion of providing incentives to the development of competition through minimum stay and wires charge exemptions was born. While no specific reference is made to excluding retail electric cooperatives from the exemption programs, the Cooperatives believe that other references and language used in S.B. 651 illustrate that there was never the intent to require that the exemption programs be applied to the Virginia Distribution Cooperatives.

First, the Cooperatives would call attention to conditions precedent to the availability of the new exemptions. In each case, commencement of the exemption program is made subject to two conditions: (1) the availability of capped rate service and, more importantly, (2) the transfer of management and control of an *incumbent electric utility's transmission assets* to a regional transmission entity after Commission approval. As many in the industry are well aware, two investor-owned incumbent electric utilities in Virginia are deeply involved in high profile, multi-level regulatory proceedings seeking approval of their proposals to transfer management and control of their transmission facilities to an RTO/E. Both AEP-Virginia and Dominion Virginia Power ("DVP") are participating in proceedings before both FERC and the SCC in which they hope to transfer operational control of their transmission facilities to some entity affiliated with the PJM Interconnection, Inc. In contrast, *none* of the Virginia Distribution Cooperatives is involved in comparable proceedings. None of the Virginia Distribution Cooperatives is required to transfer management and control of transmission facilities to an RTO/E. In fact, none of the Virginia Distribution Cooperatives operates or manages facilities that are characterized as being at the level generally recognized as *transmission* assets. The Cooperatives do not meet the threshold condition precedent to application of the exemption programs. The programs therefore should not apply to them.

It is clear that these exemptions are intended to operate in the context of incumbent electric utilities seeking and receiving authority to transfer control over their transmission assets to a regional transmission entity. It is equally clear that the retail electric cooperatives in Virginia will not be making any such transfer of transmission management or control. Therefore, the exemptions do not apply to Virginia's retail distribution cooperatives.

A second indicator that the Cooperatives were never intended to be included within the coverage of these new exemption provisions appears in the elements included in the calculation of the "market-based costs" at which energy is to be sold in the event of a failure to satisfy the terms of the exemption. In addition to the actual expense of procuring energy and related administrative and transactional costs, the statute authorizes collection of "a reasonable margin." From all appearances, this added margin is intended to allow collection of something beyond the simple cost of service – apparently contemplating something akin to a profit. Virginia's retail electric cooperatives are, of course, not for profit organizations. Describing the allowable elements of costs in terms of an "actual costs plus a margin" arrangement suggests that inclusions of the not-for-profit electric Cooperatives was not truly contemplated. As emphasized below in Question No. 4, if the Cooperatives are included, a separate and different interpretation of the statute's allowance of a reasonable margin will need to be developed.

The Cooperatives believe that the General Assembly never intended that they be required to make the new exemption programs available to their consumers, and also believe that including the Cooperatives will only add another level of complication to the process of establishing the procedures, rules and regulations for these programs. If anything, the Cooperatives believe they should be permitted, on a coop-by-coop basis, voluntarily to offer their customers comparable options with as little additional regulatory burden as possible.

4. Describe, in reasonable detail, the methodology that should be used to determine "market-based costs." Such description should address each of the three cost components: "(i) actual expenses of procuring such electric energy from the market, (ii) additional administrative and transaction costs associated with procuring such energy, including, but not limited to, costs of transmission line losses, and ancillary services, and (iii) a reasonable margin." Specifically, for each component, identify (1) each cost item that should be considered within that component; (2) how each such cost item should be determined, including the informational source of any data needed in such determination (differentiate between actual and estimated costs and also, to the extent relevant, differentiate between incremental cost and fully allocated cost, including the application of cost overheads); and (3) an explanation of the economic rationale for the determination of a reasonable margin.

As is stated in the response to Question No. 3, above, the Cooperatives maintain that it was never intended that the Cooperatives be required to offer the exemptions from the minimum stay and wires charges obligations added by the 2004 amendments to the Restructuring Act. While not straying from that position, the Cooperatives would like to offer the following comments on the determination of "market-based costs." All references applying these comments to the Cooperatives and their situation(s) are offered only by way of example or for consideration in the alternative.

The "market-based costs" should include all the end costs, including capacity costs, of procuring electrical energy for a customer who returns to the utility. However, to a large degree, the components of market-based cost are specifically prescribed by statute. Therefore, for purposes of these two new exemptions, the three cost components described in §56-577.E.2 and §56-583.E.3 of the Code will provide the primary basis for and will largely control the methodology to be used to determine "market-based costs." There is really not a lot of choice in the matter. According to the statute, the market-based costs at which a customer taking advantage of the exemption(s) must agree to purchase electric energy *shall include* the actual energy cost, administrative and transactional costs, and a reasonable margin. It would appear that the focus of the discussion should be on the underlying method to be used to determine a value for each of the three sub-components.

For the Cooperatives, the issue would be complicated by their wholesale power purchase arrangements. The Old Dominion-Member Cooperatives rely on Old Dominion for most all of their energy and capacity requirements. The Virginia Cooperatives not involved with Old Dominion also, for the most part, rely on other power suppliers. For both groups, the actual expense of procuring energy from the market is not under their immediate control. Their actual energy cost would be controlled by another entity. That energy cost presumably would include administrative and transactional costs, and may include a margin. In addition, each Cooperative would have its own administrative costs and could be expected to seek some "margin" to compensate it for the risk involved in such transactions and other factors. This being the case, there would be, in theory, two-tiers of the statutory cost components that are to be considered in setting the market-based costs, one at the wholesale level and one at the retail level. How the process would work for the non-Old Dominion Cooperatives is at this time unknown; for the Old Dominion Cooperatives, a method to break out the incremental energy and administrative costs associated with the returning customers would have to be added to the billing process. As an additional general matter, each incumbent electric utility offering sales at the retail level would have to put in place a tariff or some other approved charge that would allow it to recover these market-based costs from customers who leave and then return. It would likely require some time to develop and coordinate changes to the tariffs.

The first critical step in determining the market-based costs relates to what market and what measure is to be used to set the "actual expense of procuring … electric energy from the market" (the "market price") to be used as a component of the market-based cost. Short-term power purchase arrangements will be necessary for customers unexpectedly returning to the incumbent utility. Therefore, the market price component should reflect the relative volatility of short-term power markets. In the Cooperatives' view, for purposes of general applicability, a real-time price from a liquid market likely would be the best indicator of actual energy costs on which an administratively determined, Commission approved market-based cost could be constructed. However, if real time energy pricing is used, the customer would not know what he/she is being charged until after the fact. This may cause confusion and generate many questions, and additional resources will need to be committed to providing answers.

There are several methods now in place for setting market prices for generation. Over the past few years, under Va. Code §56-583.A., the Commission has used forward prices from several power exchanges over a specified ten-day historical period to set the generation market price for purposes of determining wires charges. Section 56-585.C provides another method for evaluating the price of energy and capacity in competitive regional electricity markets for purposes of determining default service rates for investor-owned electric utilities after capped rates are lifted. For the Cooperatives, rates for default service are to be the distribution cooperative's prudently incurred costs. In the future, when all the regional transmission organization/entity issues are resolved, the appropriate market price will likely be the real-time price set at a given location in the regional market established by that RTO/E. In short, a hodge-podge of methodologies for determining generation market prices is already developing. Whatever method is chosen for setting a generation market price, a significant effort must be made to keep confusion to a minimum and assure that several different market price methodologies are not applicable to a given situation.

Thus far we have discussed but one component of the "market-based cost," to which other cost components must be added. The new notion of market-based costs also is to include the "additional administrative and transaction costs associated with procuring such energy, including, but not limited to, costs of transmission line losses, and ancillary services." With this definition, the Cooperatives believe that it is proper to include the costs of ancillary services required to deliver the required energy across the transmission grid, the costs of average line losses and various transaction costs, such as scheduling and capacity.

For transmission line losses, the costs attributed to average line losses will have to be used for the time being. However, in a PJM-type system, losses are part of the cost calculations and can be readily identified and charged. PJM does not yet have in place a process for charging for marginal losses. If a PJM-type system is put in place and a charge for marginal losses is developed, the returning customers should bear their share of marginal losses. Therefore, some flexibility must be allowed for determining how future changes in line loss calculations are applied. A second issue relative to line losses is sub-transmission losses. By way of example, PJM applies losses across its system, but numerous Cooperative delivery points are sub-transmission and would not be included in that loss factor. In Old Dominion's case, it is currently charged for additional losses, losses attributed to deliveries across sub-transmission delivery points, through its agreements with DVP and Conectiv. Any such additional costs also must be incorporated in charges to returning customers.

Capacity costs also must be included in the additional costs calculations. By way of example, Old Dominion incurs additional costs relative to capacity obligations in PJM whenever its load changes. Thus, to protect existing customers, the costs of any obligations relative to additional capacity for returning customers must be attributed to the returning customers. This is the situation as it exists now in PJM and likely will be the case in the event Dominion Virginia Power joins the RTO.

According to the statute, the market-based cost shall also include a "reasonable margin." Determining the economic rationale for the determination of a reasonable margin may present a real challenge. This notion of adding a reasonable margin to a market-based price is a curious one and is likely to produce significant confusion. First, it is not clear from the statute what this added margin is intended to cover, *i.e.*, whether it's a profit margin, a rate of return, a margin on interest or something else. This idea of an added margin is part of the reason the Cooperatives should not be required to grant the new statutory exemptions. If these provisions are regarded as applicable to the Cooperatives, there will have to be a split between the treatment of the investor-owned utilities and the Cooperatives with regard to the "reasonable margin" issue. As not-for-profit entities, the Cooperatives do not use the term "margins" in the same context as their investor-owned brethren.

5. How will the Commission be assured that:

   a. an incumbent utility purchases electric energy from the market without adversely affecting itself or retail customers?

The statute states that "[t]he methodology established by the Commission for determining market-based costs shall be consistent with the goal[] of ... ensuring that neither incumbent utilities nor retail customers that do not choose to obtain electric energy from alternate suppliers are adversely affected." The question is not so much how the Commission *will be assured* of the absence of an adverse effect as it is how the Commission *will assure* that neither incumbent utilities nor their customers are adversely affected. Along with the goal of promoting effective competition and economic development (discussed below in Question No. 6) the Commission must also recognize the protection of electric utilities and their customers as one of its goals. This can best be met by assuring that utilities are able to fully recover all the costs related to acquiring energy and serving these customers that have been permitted to switch suppliers without compensating the utility for stranded costs and that are not bound to a minimum stay upon returning, such that the utility does not suffer a loss and no costs are shifted to other customers.

   b. an incumbent utility purchases electric energy to assure minimum cost for such energy?

The statute does not require that the Commission assure or be assured that an incumbent utility purchases electric energy to assure minimum cost for such energy. The Commission is never called upon assure or be assured of that service is provided at the minimum cost. The normal emphasis, especially in a regulated environment, is on seeking assurances that costs are just and reasonable. If the development of effective competition is indeed a goal, there should be no effort made to assure the minimum cost. The "market-based costs" should reflect, at best, reasonable costs in a given market under the given conditions.

> c. an incumbent utility uses appropriate hedging techniques in the purchase of electric energy? Should the cost of any hedging techniques be included among the "actual expenses" of electric energy?

In the Cooperatives' view, the Commission should not be expending any time or effort attempting to judge or otherwise regulate "appropriate hedging techniques." In addition, any gains or losses associated with hedging techniques probably should not bear on the determination of the "market-based costs" established for the purposes of these exemptions.

> 6. Given the requirement that the methodology to determine "market-based costs" must be consistent with the goal of promoting economic development within the Commonwealth, as well as promoting effective competition, should issues associated with the level and stability of rates and prices reflecting "market-based costs" be considered? If so, how?

As discussed in response to Question No. 4, the 2004 amendments to the Restructuring Act specifically prescribe the elements to be included in the determination of the "market-based costs." According to the statute, as revised, the market-based costs shall include the actual energy cost, administrative and transactional costs, and a reasonable margin. The Cooperatives maintain that the methods and factors to be used to determine a value for each of the three sub-components are the only matters truly at issue here.

Certain aspirational goals also are stated in the amendments to the Restructuring Act. Again, according to the statute, the methodology for determining "market-based costs" is to be consistent with the goals of: (1) promoting the development of effective competition in Virginia; (2) promoting economic development in Virginia; (3) ensuring that incumbent utilities are not adversely affected; and (4) ensuring that retail customers not choosing alternate suppliers are not adversely affected. No greater value attaches to one of these goals over another. The General Assembly appears to have determined simply that the public interest requires consideration of each and all of these goals.

So then, how should "issues associated with the level and stability of rates and prices ... be considered"? Put in the context of promoting economic development and effective competition, consideration of the *level* and *stability* of costs and prices appears to suggest consideration of *rate controls* and *price caps*. The Cooperatives find it difficult to coordinate the obligation to include the "actual expenses of procuring such electric energy" and "additional administrative and transaction costs" with consideration of issues associated with the level and stability of costs and prices (in the interest of competition and development), especially when the avoidance of adverse effects on incumbent utilities and their non-switching customers is also a stated goal. In the Cooperatives' view, while there may be a variety of issues to evaluate when considering the goals with which market-based costs are to be consistent, the level and stability of rates and prices for customers that have returned after choosing a CSP would be difficult to rationalize and should not be among them.

7. Should the ultimate methodology to determine "market-based costs" be permitted to vary among incumbent utilities? Explain why or why not.

If the Cooperatives are required to offer the exemption programs to their customers, it may be necessary to permit the methodology to determine market-based costs to vary among incumbent utilities. As discussed earlier herein, in the response to Question No. 4, the notion of allowing for a "reasonable margin," however the term "margin" is interpreted, can be expected to require a different interpretation for cooperatives. In addition, to the extent any of the goals to be considered in setting the "market-based costs" have the effect of holding those calculated costs to levels below actual costs, the Cooperatives, who operate as not-for-profit entities and without the ability to shift costs to shareholders, and their members would be adversely affected.

8. Interpret the extent of the legislated jurisdiction provided to the Commission with respect to the determination of "market-based costs," for example:

   a. Is the Commission's jurisdiction strictly limited to determination and approval of a methodology?

It appears that for the most part, the Commission's jurisdiction is limited to determination and approval of a methodology for determining market-based costs. As amended, the statute calls upon the Commission to determine and approve the methodology for ascertaining an incumbent utility's market-based costs, subject only to notice and opportunity for hearing and review of any plan to procure electric energy for the subject returning customers. Outside of a complaint that the rates produced by the methodology are not just and reasonable or that the methodology is not being properly administered, once it is established there appears to be little reason or opportunity to re-open the proceeding and re-evaluate the methodology.

   b. How frequently may and should the Commission review and/or modify the approved methodology?

The Commission should review and/or modify the approved methodology only when the incumbent electric utilities request that the methodology be re-assessed or is reconsideration is found justified in response to a specific complaint about the methodology is operating. Nothing in the statute suggests that a periodic review is necessary or appropriate. Further, in the event the same methodology is employed by all incumbent utilities, the Commission should be even more reluctant to call for reviews and modifications.

c. Does the Commission's jurisdiction extend to oversight of the actual determination of "market-based costs," including the audit, calculation, and billing of such costs and dispute resolution?

While this new notion of establishing costs for rate-setting purposes is identified as "market-based," it appears to be simply a different method for setting what is, in essence, a regulated rate. The rate has little to do with competitive market pricing, other than to the extent it reflects the actual, market-based cost for obtaining electric energy for a short term on short notice. The Commission's jurisdiction would appear to extend to prior review and approval of the methodology for determining the market-based costs, and then to only an after-the-fact examination of the actual determination/calculation and billing of such costs, *e.g.*, as part of a regular audit or in response to specific complaint. Much of such an examination would pertain to whether the proper values and calculations were applied in setting the market-based costs, as opposed to a reconsideration of the approved methodology for determining such costs.

9. Given the Wires Charge exemption program requirement for 60 days' prior notice to the incumbent utility for the return to service and purchase of retail electric energy at "market-based costs," who, if anyone, is obligated to serve a participating customer for those 60 days, and at what price, if such customer's competitive service provider defaults and there are no competitive options available to the customer?

The Cooperatives elect not to comment on this question at this time.

10. What demand threshold should be established for aggregated customer participation in the Wires Charge exemption program? Explain why.

The Cooperatives elect not to comment on this question at this time.

11. Subsequent to the eighteen-month demand limitation on participation in the Wires Charge exemption program, should such limitations be completely eliminated? Explain why or why not?

The Cooperatives elect not to comment on this question at this time.